CAPITAL COST MODELS FOR GEOTHERMAL
POWER PLANTS AND FLUID TRANSMISSION SYSTEMS

by
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SUMMARY

The GEOCOST computer program is a simulation model for evaluating the economics of developing geothermal resources. The model has been shown to be both an accurate predictor of geothermal power production facility costs and a valid designer of such facilities.

GEOCOST first designs a facility using thermodynamic optimization routines and then estimates costs for the selected design using cost models. Costs generated in this manner appear to correspond closely with detailed cost estimates made by industry planning groups. Through the use of this model, geothermal power production costs can be rapidly and accurately estimated for many alternative sites making the evaluation process much simpler yet more meaningful.

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INTRODUCTION

The GEOCOST computer program was developed by Battelle, Pacific Northwest Laboratories, to simulate the economics of constructing and operating an electrical generation facility using a geothermal resource.⁽¹⁻⁴⁾ GEOCOST is intended to model second and third generation facility designs, rather than the more expensive first-of-a-kind designs. The geothermal facilities at The Geysers were chosen as the basis for these earlier generation designs. In the modeling process, GEOCOST first designs it's "average" earlier generation facility, and then estimates capital costs for the facility.

Actual installed costs will differ from GEOCOST calculated costs because the design of an actual facility will differ from the "average" facility design. There will also be differences in site characteristics such as weather conditions, labor quality, material availability, and terrain restrictions. (GEOCOST estimates are based on site characteristics equivalent to those of Albuquerque, New Mexico.)

Costs for the facilities are estimated using component cost models. These cost models calculate installed costs for facility components as a function of required operating capacities. For example, the installed cost for a power plant crane is a function of the power output capacity of the plant, and the installed cost for the booster pumps required in the transmission pipeline is a function of the head and the flow rate through the pump.

Cost data were obtained mostly from industry suppliers. Obtaining costs was sometimes difficult due to rapidly fluctuating equipment prices and the specialized requirements of geothermal facilities. Where reliable cost data could not be obtained from suppliers or geothermal facility operators, an independent architectural engineering firm, Vitro Engineering, was used to estimate component costs.

Cost data were correlated using regression techniques to derive the cost models. Cost models are of the form:

$$\text{Cost } (\$10^3) = a + b (x)^s \text{ or } \text{Cost } (\$10^3) = a + b (x)^s + c(y)^t$$

The independent variable, or predictor variable, is represented by x and y, while a represents the fixed costs, b and c represent variable costs, and s and t represent scaling factors. All costs are in January 1977 dollars.

This report describes the cost models specifically associated with the piping transmission systems, power plants (binary and flashed steam cycle), heat rejection systems, and switchyards. Included are descriptions of facility components, and analyses of cost variances, and comparisons with other cost estimates. Design assumptions, the categorization of facility components, and the basis for the cost models are also described. The variance analysis discusses the accuracy of GEOCOST estimates. In addition, GEOCOST calculated costs are compared with actual geothermal facility cost estimates to establish the validity of the models.

STEAM PLANT

Steam Plant cost models were developed to estimate the costs of components for flashed steam cycle power plants. The categorization of plant equipment into component cost accounts is necessary before the cost models can be derived. The cost accounts utilized in GEOCOST were chosen to conform to the reference design for the power plant. However, in comparing a specific GEOCOST account cost with a cost from a similar account in another estimate it must be remembered that identical categorization between estimates is rarely achieved. Figure 1 illustrates the reference design for the flashed steam cycle power plant. Table 1 lists the plant components shown in the reference design and their respective cost accounts in GEOCOST. A complete listing of all cost model coefficients is contained in Table 2.

FIGURE 1. Flashed Steam Cycle Power Plant

TABLE 1. Categorization of Flashed Steam Power Plant Components into Cost Accounts

Account	Component
Piping and Insulation (1.1)	Pipe - Flash Vessel to Turbine - Flash Vessel to Ejectors - Turbine to Barometric Condenser - Ejectors to Condensers - Condensers to Hotwell - Hotwell to Cooling Tower - Cooling Tower to Coldwell - Coldwell to Coolers - Coldwell to Condensers - Coolers to Hotwell - Cooling Tower to Reject Water Reinjection Pump - Flash Vessel to Flash Water Reinjection Pump
Crane (1.2)	Not Shown
Turbogenerator (1.3)	Generator Turbine
Flash Vessel (1.6)	Flash Vessel
Misc. Process Support Equipment (1.9)	Intercondenser Aftercondenser Turbine Oil Cooler Hydrogen Cooler
Instrumentation & Controllers (1.10)	See Account Description
Electrical Support Equipment (1.12)	See Account Description
Condenser (1.16)	Barometric Condenser
Buildings, Foundations, and Support Equipment (1.18)	Hotwell Coldwell
Gas Ejectors (1.19)	First Stage Ejector Second Stage Ejector
Cooling Water Pump (1.20)	Cooling Water Pump
Flash Water Reinjection Pump (1.21)	Flash Water Reinjection Pump
Reject Water Reinjection Pump (1.22)	Reject Water Reinjection Pump
Condensate Pump (1.23)	Condensate Pump
Wet Cooling Tower (2.1)	Cooling Tower
Dry Cooling Tower (2.2)	Cooling Tower
Switchyard (3.1)	Not Shown
Hydrogen Sulfide Removal System (4.1)	Not Shown

TABLE 2. Flashed Steam Power Plant Capital Cost Coefficients, $\$10^3$ (1977);
Cost ($\$10^3$) = a + b (x)⁵

Account Number	Component	a	b	s	Comments
1.0	Power Plant				
1.1	Piping and Insulation				
	Carbon Steel/Motor Pumped System	213	3.23E-4	0.9	x = Total Steam Flow Rate at Flasher Exit(s), ft ³ /hr
	Carbon Steel/Turbine Pumped System	258	7.42E-4	0.87	x = Total Steam Flow Rate at Flasher Exit(s), ft ³ /hr
	Stainless Steel/Motor Pumped System	533	3.77E-3	0.80	x = Total Steam Flow Rate at Flasher Exit(s), ft ³ /hr
	Stainless Steel/Turbine Pumped System	614	1.76E-3	0.87	x = Total Steam Flow Rate at Flasher Exit(s), ft ³ /hr
1.2	Crane	206	0.69	1	x = Gross Plant Power, MWe
1.3	Turbogenerator		8.8E-3	-0.171	x = Gross Plant Power, MWe
			x 1	1.015	x = Total Steam Flow Rate, lb/hr
1.6	Flash Vessel(s)		0.028	0.238	x = Inlet Pressure, psia
			x 1	0.579	x = Total Steam Flow Rate at Outlet(s), lb/hr
1.9	Misc. Process Support Equipment	0	5.7	0.85	x = Gross Plant Power, MWe
1.10	Instrumentation and Controllers	See Component Description			
1.12	Electrical Support Equipment	See Component Description			
1.16	Condenser	470	7.75E-4	1	x = Total Steam Flow Rate, lb/hr
1.18	Building, Structures, and Foundations	315	29.88	1	x = Gross Plant Power, MWe
1.19	Gas Ejectors (Steam Driven)	97	1.99	0.6	x = Gas Ejection Rate, ft ³ /min
1.20	Cooling Water Pump				
	Motor Driven/Carbon Steel	34.3	3.54E-3	0.785	x = Water Flow Rate (10 ³ lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	121.1	2.21E-4	0.997	x = Water Flow Rate (10 ³ lb/hr) x Pump Head (psi)
	Motor Driven/Stainless Steel	174.3	5.50E-3	0.846	x = Water Flow Rate (10 ³ lb/hr) x Pump Head (psi)
	Turbine Driven/Stainless Steel	262.3	2.44E-3	0.908	x = Water Flow Rate (10 ³ lb/hr) x Pump Head (psi)

TABLE 2. (Continued)

Account Number	Component	a	b	s	Comments
1.21	Flash Water Reinjection Pump				
1.22	Reject Water Reinjection Pump				
	Motor Driven/Carbon Steel	0.0222	0.624		x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
		x 1	0.138		x = Discharge Pressure (psia)
	Turbine Driven/Carbon Steel	0.0869	0.526		x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
		x 1	0.256		x = Discharge Pressure (psia)
	Motor Driven/Stainless Steel	0.0984	0.608		x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
		x 1	0.162		x = Discharge Pressure (psia)
	Turbine Driven/Stainless Steel	0.1565	0.574		x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
		x 1	0.201		x = Discharge Pressure (psia)
1.23	Condensate Pump				
	Motor Driven/Carbon Steel	79.9	9.0E-6	1.201	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	160.5	1.51E-4	1.031	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Motor Driven/Stainless Steel	337.9	2.70E-4	1.064	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Stainless Steel	419.6	4.09E-4	1.043	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
2.0	<u>Heat Rejection System</u>				
2.1	Wet Cooling Tower				
	Conventional Wood Construction	0	6.95E-3	1	x = Required Tower Units
	Concrete Construction	0	1.11E-2	1	x = Required Tower Units
2.2	Dry Cooling Tower	0	9280	1	x = Heat Rejected From Tower, 10^9 Btu/hr

TABLE 2. (Continued)

<u>Account Number</u>	<u>Component</u>	<u>a</u>	<u>b</u>	<u>s</u>	<u>Comments</u>
3.0	<u>Switchyard</u>				
3.1	Switchyard	7.6	120	0.52	x = Gross Plant Power, MWe
4.0	<u>Hydrogen Sulfide Removal System</u>				
4.1	Hydrogen Sulfide Removal Unit	0	293.17	.529	x = Gross Plant Power, MWe
5.0	<u>Other Costs</u>				
5.1	Indirect Field Expense	0	0.10	1	x = Direct Field Cost (i.e., Total Component Costs)
5.2	Engineering and Design	0	0.12	1	x = Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)
5.3	Contractors Fee	0	0.05	1	x = Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)
5.4	Contingency	0	0.13	1	x = Optional - Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)

GEOCOST has the capability to model a steam cycle facility in four modes. In the first mode, dry steam is transported to the power plant in the second mode, steam is flashed and separated at the wellhead and then transported to the power plant. In this mode, the costs for the flash vessel and steam separator at the wellhead are part of the energy supply cost and are not included as a power plant cost. In the third mode, geothermal fluid is transported to the power plant and then flashed. The flash vessel is included as a flash plant cost. The fourth operating mode is a multiple flash option combining both wellhead and plant flashing; equipment costs at the wellhead are part of the energy supply costs and equipment costs at the plant are part of the power plant costs.

PIPE AND INSULATION (ACCOUNT 1.1)

This cost model was derived from the cost data developed in the Vitro Engineering study.⁽⁵⁾ Separate models were derived for turbine or electric motor pumped systems using either stainless or carbon steel pipe materials (Figure 2). Pipe, fitting, valve, and pipe support costs are included in this account. Pipe insulation is assumed to be calcium silicate material ranging in thickness from 1-1/2 to 4-1/2 in. depending upon internal pipe temperatures.

CRANE (ACCOUNT 1.2)

This account calculates the costs for the overhead crane required in the power plant building. Maintenance requirements necessitate that the crane be capable of lifting all equipment within the plant. Cost information from power plants at The Geysers and an industry supplier, Crane Company, was used in deriving the model.

TURBOGENERATOR (ACCOUNT 1.3)

Steam plant turbogenerator costs are calculated as a function of steam flow rates and power output.⁽⁶⁻¹⁷⁾ The cost of the generator primarily depends on power output. The cost of the turbine is based on turbine weight, which in turn depends on steam flow rates. Figure 3 shows the turbogenerator cost model and sources of cost data. The turbine design utilized in GEOCOST

FIGURE 2. Pipe and Insulation Installed Costs (Flash Plant Account 1.1)

exhausts below atmospheric pressure. The number of turbine inlet stages equals the total number of flashing and separating stages at both the wellhead and power plant. The generator is designed as a three-phase, hydrogen-cooled, AC synchronous generator. An internal turbogenerator efficiency of 75% is assumed in the model.

FIGURE 3. Turbogenerator Installed Costs (Flash Plant Account 1.3)

FLASH VESSEL (ACCOUNT 1.6)

This model estimates costs for plant size horizontal flash vessels. The model is used once in estimating total flash vessel costs power plant regardless of the number of flash vessels in the power plant. First flash stage fluid inlet pressure and total flow rates exiting the flash vessel(s) determine installed costs. Cost data for this account were obtained from a tank supplier, Goslin-Birmingham, Inc., and cost estimates were made by two architectural engineering firms, Ben Holt Company and Bechtel Corporation. (18-20)

MISCELLANEOUS PROCESS SUPPORT EQUIPMENT (ACCOUNT 1.9)

This account calculates the costs for miscellaneous process equipment within the generating plant, including minor condensers, coolers, mufflers, steam scrubbers, and other nonspecified equipment. Cost data were obtained from utilities operating geothermal facilities.⁽⁶⁻¹²⁾

INSTRUMENTATION AND CONTROLLERS (ACCOUNT 1.10)

Instrumentation and controller costs for the flashed steam plant are calculated as a percent of component account costs. Table 3 lists these percentages for each component account. For example, the instrumentation and controller cost for the condenser equals 17.8% of the condenser cost model calculated cost. Total instrumentation and controller cost for the plant is the summation of these percent costs. The Vitro Engineering study was the source of these percentage multipliers.⁽⁵⁾

TABLE 3. Percent Multipliers for Instrumentation and Controllers

<u>Component Account</u>	<u>Account No.</u>	<u>% of Capital Cost</u>
Pumps	1.20-1.23	5.5
Flash Vessels	1.6	10.9
Buildings, Structures, and Foundations	1.18	5.8
Cooling Towers	2.1-2.2	1.2
Misc. Process Support Equipment	1.9	13.1
Condenser	1.16	17.8

ELECTRICAL SUPPORT EQUIPMENT (ACCOUNT 1.12)

Electrical support equipment costs are calculated in the same manner as instrumentation and controllers. Table 4 lists the percentages used for each component account. These percentages were also determined by Vitro Engineering.⁽⁵⁾ Included in this account is most electrical equipment in the plant with the exception of the generator.

TABLE 4. Percent Multipliers for Electrical Support Equipment

<u>Component Account</u>	<u>Account No.</u>	<u>% of Capital Cost</u>
Pumps - Motor	1.20-1.23	5.7
Pumps - Turbine	1.20-1.23	0.9
Flash Vessels	1.6	9.0
Buildings, Structures and Foundations	1.18	4.2
Cooling Towers	2.1-2.2	4.6
Misc. Process Support Equipment	1.9	14.9
Condenser	1.16	3.6

CONDENSER (ACCOUNT 1.16)

Cost data used in the formulation of a condenser cost model were taken from two industry suppliers: Ingersoll Rand and Southwest Engineering. Ingersoll Rand supplied costs for barometric spray condensers and Southwest Engineering supplied costs for indirect condensers. Costs were nearly identical for both types of condensers.⁽²¹⁾

BUILDINGS, FOUNDATIONS, AND SUPPORT EQUIPMENT (ACCOUNT 1.18)

This account includes costs for the building shell and foundations, site work, and personnel service facilities. These costs are very site-dependent, resulting in considerable variation in the cost data. The model is based on costs taken from utilities operating The Geysers and other geothermal facilities.⁽⁶⁻¹⁵⁾

GAS EJECTORS (ACCOUNT 1.19)

The method selected for removing noncondensable gases from the barometric condenser is a two-stage steam jet ejector with inter- and after-condensers. Costs for both these ejectors are calculated in a single cost account. Ejector costs were obtained from an industry supplier, Worthington Manufacturing.

COOLING WATER PUMP (ACCOUNT 1.20) AND CONDENSATE PUMP (ACCOUNT 1.23)

Cost models for these accounts were derived from the Vitro Engineering study.⁽⁵⁾ The models are based on vertical turbine pump costs and include costs for the motor, turbine, column, and bowls. Costs are calculated as a function of head (pressure change) and capacity (flow rate). Both accounts simulate pumps operating in low pressure environments where suction pressures are nearly atmospheric. Figure 4 illustrates the cooling water pump model. Cost models are available for carbon or stainless steel pump material with electric or turbine drives.

FIGURE 4. Cooling Water Pump Installed Costs (Account 1.20)

FLASH WATER REINJECTION PUMP (ACCOUNT 1.21) AND REJECT WATER REINJECTION PUMP (ACCOUNT 1.22)

These cost models were derived from the Vitro Engineering study cooling water, pump cost data.⁽⁵⁾ An additional variable was applied to the models to reflect the increased cost of reinjection pumps operating with high discharge pressures. The use of exotic high-strength materials and thicker casings results in this cost increase. Pump suppliers were consulted and a multiplier term was developed to properly estimate these cost increases for reinjection pumps. Reinjection pump costs are shown in Figure 5.

FIGURE 5. Reinjection Pump Installed Costs (Account 1.21 and 1.22)

WET COOLING TOWER (ACCOUNT 2.1)

The wet cooling tower cost model is based on Marley Company mechanical draft, wet cooling tower costs.⁽²²⁾ Cost models are available for both conventional wood towers and the newer concrete towers. Concrete towers are approximately 60% more expensive than wood towers but are more durable and totally fireproof. Cooling tower costs for both wood and concrete construction are shown in Figure 6.

FIGURE 6. Wet Cooling Tower Installed Costs (Account 2.1)

Wet cooling tower costs are calculated as a function of the "required tower units" where

$$\text{Required Tower Units} = \text{Rating Factor} \times \text{Cooling Water Flow Rate into Tower (gpm)}$$

The rating factor defines the relative degree-of-difficulty in cooling. The factor can be calculated from the following equation.

$$\begin{aligned} \text{Rating Factor} = & 3.76 - 0.0524 (\text{WBT}) + 0.1347 (R) - 0.1725 (A) \\ & + 0.00019 (\text{WBT})^2 - 0.00081 (R)^2 + 0.00196 (A)^2 \\ & - 0.00073 (\text{WBT})(R) + 0.00107 (\text{WBT})(A) - 0.0013 (R)(A) \end{aligned}$$

where

WBT = Wet Bulb Temperature (°F)

R = Range (°F, difference between cooling water inlet temperature and cooling water outlet temperature)

A = Approach to Cooling Tower (°F)

DRY COOLING TOWER (ACCOUNT 2.2)

Cost estimates for natural draft dry cooling towers were obtained from R.W. Beck and Associates.⁽²³⁾ These towers are very expensive due to their steel and aluminum construction. Unlike the wet cooling tower, costs for this account are based on the amount of heat rejected to the atmosphere from the tower.

SWITCHYARD (ACCOUNT 3.1)

The switchyard account calculates the costs for the plant-located switchyard. Costs for the electrical transmission lines leaving the power plant are not included as a part of the account. Cost data were obtained from utilities.⁽⁶⁻¹⁷⁾

HYDROGEN SULFIDE REMOVAL SYSTEM (ACCOUNT 4.1)

A filtering system for hydrogen sulfide emissions is available as an option in the plant design. The equipment can remove up to 95% of the hydrogen

sulfide content from aftercondenser vent gases. The removal system can either be an integral part of a single power plant or a separate facility receiving vent gases from multiple plants. Conceptual designs are based on Niland process conditions. The cost model for this system was based on cost estimates made by the EIC Corporation.⁽²⁴⁾

INDIRECT FIELD COST (ACCOUNT 5.1)

Costs for this account are approximated as 10% of the direct field cost. Direct field cost is the summation of costs from accounts 1.1 through 4.1. Included as an indirect cost are construction expenses for contractor mobilization on the site, utility hookups, and field and home office overheads. Payroll burdens for worker compensation, insurance, employee funds, and fringe benefits are also included as indirect expenses. Costs for tooling, warehousing, minor equipment requirements, and plant testing prior to owner acceptance are the remaining indirect costs.

The percentages GEOCOST uses to estimate indirect field cost and three other indirect costs--engineering and design, contractors fee, and contingency--are a consensus of the indirect cost percentages found in six geothermal power plant cost estimates made independently by industry planning groups.^(11,12,19,20,25,26) Percentages vary somewhat between estimates but the total indirect cost burden is always about 40% of direct field cost.

ENGINEERING AND DESIGN (ACCOUNT 5.2)

The allowance for engineering and design expenses can be approximated as 12% of total field cost. Direct field cost plus indirect field cost equals total field cost. This account calculates costs for all home and field office expenses resulting from the engineering and designing of the facility.

CONTRACTOR'S FEE (ACCOUNT 5.3)

The profit required by the contractor is assumed to equal 5% of total field cost. The real profit percentage to the contractor will remain at this level regardless of the risk of unanticipated construction expenses occurring. The contractors allowance for risk is determined in the contingency account.

CONTINGENCY (ACCOUNT 5.4)

Contingency is the allowance provided a contractor to cover unestimated construction expenses. The allowance is assumed to equal 13% of total field cost. Contingency allowance is an estimating tool for the contractors use only and should not be viewed as a cost subject to contractor/owner negotiations. Occasionally, in a reimbursable type contract, the contingency allowance is subject to negotiation. In this case, the contractor's fee which is determined from the contingency percentage is being negotiated and not the contingency itself. The real contingency allowance reflects the perceived uncertainty of construction costs and not the profit intentions of the contractor.

The contractor's perception of construction risk resulting from extra costs determines the contingency percentage. If the risk is perceived as being very great, the percentage will be high. Occasionally a contractor will estimate using unrealistically high contingencies, when construction risk is actually low. Under these circumstances, the contractor is simply allotting for a large profit allowance disguised in the estimate as contingency.

Very rarely does the contingency allowance match exactly the unanticipated costs. In a lumped sum contract, the contractor would lose or gain by the difference. However, over many construction projects the losses will tend to cancel out the gains and average contingency actually used will closely approximate the contingency allowance. In a reimbursable contract, contingency is irrelevant to the contractor because all costs are paid by the owner.

BINARY PLANT

Binary plant cost models estimate costs for binary cycle power plants, cooling towers, and switchyards. The reference design for the binary plants is shown in Figure 7. Listed in Table 5 are plant components and their respective cost accounts. A complete listing of all cost model coefficients is contained in Table 6. Binary plant equipment in some instances is identical to equipment found in the steam plant. Models calculating costs for this equipment will be identical for both types of power plants.

FIGURE 7. Subcritical Binary Fluid Cycle Power Plant

TABLE 5. Categorization of Binary Power Plant
Components into Cost Accounts

Account	Component
Piping, Insulation, and Tanks (1.1)	Pipe - Pipe-Superheater to Vaporizer - Vaporizer to Preheater - Preheater to Reinjection Pump - Superheater to K.O. Drum - K.O. Drum to Turbine - Turbine to Desuperheater/Condenser - Desuperheat/Condenser to Condensate Receiver - Condensate Receiver to Preheater - Desuperheater/Condenser to Hotwell - Hotwell to Cooling Tower - Cooling Tower to Coldwell - Coldwell to Coolers - Coolers to Hotwell - Coldwell to Desuperheater/Condenser - Knockout (K.O.) Drum - Condensate Receiver
Crane (1.2)	Not Shown
Turbogenerator (1.3)	Generator
	Turbine
Vapor Generator(s)	Superheater
	Vaporizer
	Preheater
Misc. Process Support Equipment (1.9)	Turbine Oil Cooler
	Hydrogen Cooler
Instrumentation & Controllers (1.10)	See Account Description
Electrical Support Equipment (1.12)	See Account Description
Condenser (1.16)	Desuperheater & Condenser
Buildings, Foundations, and Support Equipment (1.18)	Hotwell
	Coldwell
Cooling Water Pump (1.20)	Cooling Water Pump
Reinjection Pump (1.21)	Reinjection Pump
Condensate Pump (1.23)	Condensate Pump
Working Fluid Feed Pump (1.24)	Feed Pump
Working Fluid Booster Pump (1.25)	Booster Pump
Wet Cooling Tower (2.1)	Cooling Tower
Dry Cooling Tower (2.2)	Cooling Tower
Switchyard (3.1)	Not Shown

TABLE 6. Binary Power Plant Capital Cost Coefficients,
 $\$10^3$ (1977); Cost $(\$10^3) = a + b(x)^s$

Number Account	Component	a	b	s	Comments
1.0	<u>Power Plant</u>				
1.1	Piping, Insulation and Tanks				
	Carbon Steel/Motor	0	4.5E-3	1	x = Working Fluid Flow Rate at Turbine Inlet, ft^3/hr
	Carbon Steel/Turbine Pumped System	145	4.88E-3	1	x = Working Fluid Flow Rate at Turbine Inlet, ft^3/hr
	Stainless Steel/Motor Pumped System	11.3	5.71E-3	1	x = Working Fluid Flow Rate at Turbine Inlet, ft^3/hr
	Stainless Steel/Turbine Pumped System	8.5	6.18E-3	1	x = Working Fluid Flow Rate at Turbine Inlet, ft^3/hr
1.2	Crane	206	0.69	1	x = Gross Plant Power, MWe
1.3	Turbogenerator	665	0.40	1	x = Working Fluid Flow Rate, 10^3 lb/hr
1.5	Superheater, Vaporizer, and Preheater	0	0.1004 x F	0.78	x = Heat Transfer Area (ft^2) (See Component Description)
1.9	Misc. Process Support Equipment	0	5.7	0.85	x = Gross Plant Power, MWe
1.10	Instrumentation and Controllers	See Component Description			
1.12	Electrical Support Equipment	See Component Description			
1.16	Condenser and Desuperheater	0	0.1004 x F	0.78	x = Heat Transfer Area (ft^2) (See Component Description)
1.18	Buildings, Structures, and Foundations	5.1	91.76	0.685	x = Gross Plant Power, MWe
1.20	Cooling Water Pump				
	Motor Driven/Carbon Steel	34.3	3.54E-3	0.785	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	121.1	2.21E-4	0.997	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Motor Driven/Stainless Steel	174.3	5.50E-3	0.846	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Stainless Steel	262.3	2.44E-3	0.908	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
1.21	Reinjection Pump				
	Motor Driven/Carbon Steel	0.0222	x 1	0.624	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
				0.138	x = Discharge pressure (psia)
	Turbine Driven/Carbon Steel	0.0869	x 1	0.526	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
				0.256	x = Discharge Pressure (psia)

TABLE 6. (Continued)

Number Account	Component	a	b	s	Comments
	Motor Driven/Stainless Steel		0.0984	0.608	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
			x 1	0.162	x = Discharge Pressure (psia)
	Turbine Driven/Stainless Steel		0.1565	0.574	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
			x 1	0.201	x = Discharge Pressure (psia)
1.23	Condensate Pump				
	Motor Driven/Carbon Steel	79.9	9.0E-6	1.201	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	160.5	1.51E-4	1.031	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Motor Driven/Stainless Steel	337.9	2.70E-4	1.064	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Stainless Steel	419.6	4.09E-4	1.043	x = Water Flow Rate (10^3 lb/hr) x Pump Head (psi)
1.24	Working Fluid Feed Pump				
	Motor Driven/Carbon Steel	0	1.4E-3	0.955	x = Working Fluid Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	0	2.68E-3	0.953	x = Working Fluid Flow Rate (10^3 lb/hr) x Pump Head (psi)
1.25	Working Fluid Booster Pump				
	Motor Driven/Carbon Steel	0	9.36E-4	1.23	x = Working Fluid Flow Rate (10^3 lb/hr) x Pump Head (psi)
	Turbine Driven/Carbon Steel	130	3.14E-4	1.236	x = Working Fluid Flow Rate (10^3 lb/hr) x Pump Head (psi)
2.0	<u>Heat Reinjection System</u>				
2.1	Wet Cooling Tower				
	Conventional Wood Construction	0	6.95E-3	1	x = Required Tower Units
	Concrete Construction	0	1.11E-2	1	x = Required Tower Units
2.2	Dry Cooling Tower	0	9280	1	x = Heat Rejected from Tower 10^9 Btu/hr
3.0	<u>Switchyard</u>				
3.1	Switchyard	7.6	120	0.52	x = Gross Plant Power, MWe
5.0	<u>Other Costs</u>				
5.1	Indirect Field Expense	0	0.10	1	x = Direct Field Cost (i.e., Total Component Costs)
5.2	Engineering and Design	0	0.12	1	x = Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)
5.3	Contractors Fee	0	0.05	1	x = Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)
5.4	Contingency	0	0.13	1	x = Optional - Total Field Cost (i.e., Total Component Costs + Indirect Field Expense)

In the binary cycle, the geothermal fluid heats and vaporizes a secondary working fluid. This working fluid expands used in the power generation circuit. A third circuit circulates cooling water to condense the working fluid. The plant design shown in Figure 7 uses a subcritical Rankine Fluid Cycle. The design for a super-critical cycle is nearly identical from a costing standpoint.

PIPING, INSULATION, AND TANKS (ACCOUNT 1.1)

This cost model has the same basis as steam plant Account 1.1.⁽⁵⁾ In the binary cycle, costs for the knockout drum and condensate receiver are included in the account. The noncorrosive nature of the working fluid will allow the use of carbon steel materials rather than more expensive stainless steel materials in most instances. Cost models are shown in Figure 8.

FIGURE 8. Piping, Insulation, and Tanks Installed Costs (Binary Plant Account 1.1)

CRANE (ACCOUNT 1.2)

This cost model is identical to steam plant Account 1.2.

TURBOGENERATOR (ACCOUNT 1.3)

Binary cycle turbogenerator costs were obtained from three design estimators, Rodgers/Benham-Blair, TRW, and Bechtel Corporation. Costs were also obtained from geothermal plant operators. (16,25,27-29) The cost model formulating their data is shown in Figure 9.

FIGURE 9. Turbogenerator Installed Costs
(Binary Plant Account 1.3)

VAPOR GENERATOR (ACCOUNT 1.5) AND CONDENSER (ACCOUNT 1.16)

The cost model for tube and shell heat exchanger accounts is based on cost studies conducted at Battelle, Pacific Northwest Laboratories (BNW) and Los Alamos Scientific Laboratories (LASL). Additional cost data were obtained from the following industry suppliers: Young Radiator Company, Perfex Corporation, American Standard, and Struthers-Wells. Costs are calculated as a function of heat transfer surface area and shell and tube wall thicknesses. Heat exchanger wall thicknesses depends on internal pressures. The vapor generator account utilizes the cost model once, applying the total heat transfer surface area for all front-end heat exchangers (i.e., superheater, vaporizer, and preheater) to the model. The condenser account utilizes the model twice, first applying the desuperheater heat transfer surface area to the model, and then applying the condenser heat transfer surface area to the model. The equations used to derive the scaling factor (F) required in the cost model are shown below.

P_{Shell} = Heat Exchanger shell side pressure

P_{Tube} = Heat exchanger tube side pressure

For $P_{\text{Shell}} \leq 100$ psia and $P_{\text{Tube}} \leq 200$ psia, $F = 1.0$.

For all other situations

$$F = 0.0833 (C2) \frac{C10}{C2}^X$$

where

$$X = \frac{P_{\text{Tube}} - 200}{800}$$

$$C2 = 2.6 + 1.25 (P_{\text{Shell}})^{0.44}$$

$$C10 = 12.1 + 0.40 (P_{\text{Shell}})^{0.60}$$

MISCELLANEOUS PROCESS SUPPORT EQUIPMENT (ACCOUNT 1.9)

This cost model is identical to steam plant Account 1.9. No cost data were available for costing miscellaneous binary plant equipment so the flash plant model is being used. (6-12)

INSTRUMENTATION AND CONTROLLERS (ACCOUNT 1.10)

Costs for this account are calculated in the same manner as described in the steam plant Account 1.10 description. Table 7 lists the component accounts and percentages used for this model.⁽⁵⁾

TABLE 7. Percent Multipliers for Instrumentation and Controllers

<u>Component Account</u>	<u>Account No.</u>	<u>% of Capital Cost</u>
Pumps	1.20-1.24	5.5
Buildings, Structures, and Foundations	1.18	5.8
Cooling Towers	2.1-2.2	1.2
Misc. Process Support Equipment	1.9	13.1
Vapor Generator and Condenser	1.5-1.16	17.8

ELECTRICAL SUPPORT EQUIPMENT (ACCOUNT 1.12)

Electrical equipment costs are estimated in the same way as the steam plant electrical support equipment costs. Component accounts and percentages are listed in Table 8.⁽⁵⁾

TABLE 8. Percent Multipliers for Electrical Support Equipment

<u>Component Account</u>	<u>Account No.</u>	<u>% of Capital Cost</u>
Pumps - Motor	1.20-1.24	5.7
Pumps - Turbine	1.20-1.24	0.9
Buildings, Structures, and Foundations	1.18	4.2
Cooling Towers	2.1-2.2	4.6
Misc. Support Equipment	1.9	14.9
Vapor Generator and Condenser	1.5-1.16	3.6

BUILDINGS, FOUNDATIONS, AND SUPPORT EQUIPMENT (ACCOUNT 1.18)

This account is based on cost data taken from the Vitro Engineering study.⁽⁵⁾ Included in the account are costs for the building shell and foundations, site work, and personnel service facilities.

COOLING WATER PUMP (ACCOUNT 1.20), REINJECTION PUMP (ACCOUNT 1.21), AND CONDENSATE PUMP (ACCOUNT 1.23)

Cost models for these accounts are described in the steam plant account descriptions.

WORKING FLUID FEED PUMP (ACCOUNT 1.24) AND WORKING FLUID BOOSTER PUMP (ACCOUNT 1.25)

Costs data for these pumps were taken from the Vitro Engineering study.⁽⁵⁾ The pumps are used in the working fluid circuit and operate in high-pressure environments. A stainless steel material option was not included for working fluid pump cost models because the noncorrosiveness of the working fluid allows the use of cheaper carbon steel materials. The cost models for the feed pump are shown in Figure 10.

WET COOLING TOWER (ACCOUNT 2.1) AND DRY COOLING TOWER (ACCOUNT 2.2)

Cost models for these accounts are described in the steam plant account descriptions.

SWITCHYARD (ACCOUNT 3.1)

This cost account is discussed in steam plant Account 3.1.

INDIRECT FIELD COST (ACCOUNT 5.1), ENGINEERING AND DESIGN (ACCOUNT 3.1), CONTRACTOR FEE (ACCOUNT 5.3), AND CONTINGENCY (ACCOUNT 5.4)

Costs for these accounts are described in the steam plant account descriptions.

FIGURE 10. Working Fluid Feed Pump Installed Costs (Account 1.24)

TRANSMISSION SYSTEM

Transmission system cost models estimate costs for the geothermal fluid transmission pipeline from wellhead to power plant. Transport of both single-phase and two-phase fluids can be simulated using these cost models. Costs for wellhead equipment such as relief valving, steam separators, and rock screens are not included as a transmission system cost. When modeling flashed steam power plants, inlet pipe up to the plant-located, first stage flash vessel is considered a transmission system cost. When modeling binary cycle plants, inlet pipe up to the superheater is considered a transmission cost. In the reinjection of geothermal fluids, all pipe exiting plant-located, reinjection pumps is considered a transmission system cost.

The assumed configuration for the transmission system is shown in Figure 11. The piping layout is based on well and manifold spacing which is dependent upon the quality of the reservoir. The system is treated as an above ground pipeline over the entire transmission distances. Table 9 is a listing of transmission system components and their respective cost accounts.

FIGURE 11. Transmission System Piping Configuration

Cost model coefficients are listed in Table 10. Unlike the power plant cost models, indirect expense, engineering and design, contractor's fee and contingency costs are not calculated in separate accounts. Allowances for these costs are accumulated within component accounts themselves. Cost data were obtained from numerous industry suppliers and cost estimating manuals.

TABLE 9. Categorization of Transmission System Components into Cost Accounts

Account	Component
Pipe (1.0)	Pipe Material Pipe Fitting Material Welded Pipe Connections Valves
Insulation (2.0)	Insulation Material Insulation Installation
Casing (3.0)	Casing Material Casing Installation
Site Work (4.0)	Pipe Installation (Handling) Concrete Anchor Pad Material Pipe Support Material Support Installation Site Clearing and Grading
Pumps (5.0)	Pump Material Pump Installation

TABLE 10. Transmission System Capital Cost Coefficients, \$10³ (1977); Cost/Unit = a + b (x)s

Account Number	Component	Cost/Unit	a	b	s	Comments
1.1	Pipe	Cost/Foot	0	0.0429 x 1	0.531 1.841	x = Nominal Pipe Diameter, in. x = Pipe Schedule
1.2	Insulation					
	Calcium Silicate	Cost/Foot	-6.42	1.538	0.59	x = Insulation Cross-Sectional Area, in. ²
	Polyurethane	Cost/Foot	2.84	0.152	0.91	x = Insulation Cross-Sectional Area, in. ²
1.3	Casing	Cost/Foot	0.26	0.0166	2.024	x = Outside Insulation Diameter, in.
1.4	Site Work	Cost/Foot	14.0	1.07	1	x = Nominal Pipe Diameter, in.
1.5	Pumps	Cost/Pump	6035	0.022	1	x = Pump Capacity (GPM) x Head (ft)

PIPE (ACCOUNT 1.0)

Transmission pipe costs are calculated as a function of pipe diameter and pipe schedule (wall thickness).⁽³²⁻³⁵⁾ The pipe diameter depends on flow rates and is determined by minimizing pump operating costs, piping costs, and fluid friction losses. Pipe schedule is depends on fluid pressure and is calculated using the rules listed in Table 11.

TABLE 11. Transmission System Pipe Schedules

<u>Fluid Pressures</u>	<u>Pipe Schedule</u>
≤ 350 psia	10
≤ 550 psia and > 350 psia	20
≤ 650 psia and > 350 psia	30
≤ 1000 psia and > 650 psia	40
≤ 1050 psia and > 1000 psia	80

Carbon steel pipe with welded connections at 30-ft intervals is the assumed design for the pipeline. Expansion loops at 200-ft intervals along the pipeline are used to allow for pipe contraction when the system is not operating and cold. Pipe materials, fitting materials, and welding labor for the expansion loops are included in this account.

INSULATION (ACCOUNT 2.0)

Two insulation materials are used in the cost models: calcium silicate (3.1) and polyurethane foam (3.2). For this account, GEOCOST first determines optimal insulation thickness. In determining costs for this optimal thickness, cost of a 2-in. thickness of calcium silicate is considered first as the initial insulation layer. Cost of polyurethane foam insulation, which has a maximum heat exposure of 250°F, is then calculated over the remaining thickness required to bring total insulation thickness to the optimal level. Expansion loop insulation requirements are included in this account.^(32,33)

CASING (ACCOUNT 3.0)

The casing (insulation covering) is a 0.016-in. aluminum jacketing. All sections of the pipeline including expansion loops are covered with a casing. (32,33)

SITE WORK (ACCOUNT 4.0)

The site work account includes costs for clearing and grading the pipeline right-of-way, erecting pipe supports, installing anchor pads, and handling and aligning the pipe sections on to the supports. Pipe supports are located every 25 ft along the run of the pipeline. (32,33)

PUMP (ACCOUNT 5.0)

Booster pump stations may be required along the pipeline to keep fluids pressurized as single-phase liquid. Pump costs are based upon the amount of pressure loss occurring due to friction in the fluid flow.

Pump operating conditions range from 1000 to 3000 gpm capacity at 60 to 70 ft of head. Multiple pumps in ether parallel or series arrangements are costed as required. (32,33)

VARIANCE ANALYSIS

Capital cost estimates calculated by these models will usually differ from other cost estimates and actual costs. Variance terms provide a measure for assessing the accuracy of the cost estimates and are useful in comparing the relative merits of two different estimates.

GEOCOST estimates capital costs for one reference facility design. This reference design is specifically defined with little variation. The facility is located in Albuquerque, New Mexico, with the midpoint in facility construction to have been January 1977. For some facility components, the design definitions are specific material and equipment requirements. For example, a 10 MWe flashed steam power plant is defined to require exactly 85 ft of 2-in.-diameter pipe between the turbine inlet and gas ejectors. For other facility components, the GEOCOST design is defined as being a mix of many actual facility designs. For example, the flash plant turbogenerator cost model was derived from seven different cost data points which were the result of seven different turbogenerator designs. The cost model itself is nothing more than the average of these seven designs. By definition, this average design, whether workable or not, is the defined turbogenerator design used in GEOCOST.

Statistical analysis was used to determine the variances in individual component costs and in total power plant cost. This analysis first necessitates that the different sources of error be identified.⁽³⁴⁾

GEOCOST estimates may differ slightly from actual costs when simulating the costs of a facility of the reference design because of two error sources: "routine" error and "formulation" error. "Routine" errors are the expected minor deviations in cost that result from routine occurrences. Minor changes in weather that slightly affect costs, and minor adjustments by suppliers in their discount rates which affect prices are examples of this error. Estimates of "routine" error are listed in Table 12. "Formulation" errors are the predictive discrepancies that result from the formulation of a model from data points. Very rarely is a model able to represent all data perfectly. These predictive discrepancies result in an error term or variance that must be carried within the model.

TABLE 12. "Routine" Error Standard Deviation Assumptions^(a)

Account Description	Assumed Error
Pipe, Insulation and Tanks	10% of estimated cost
Crane	The greater of 5% of estimated cost or "formulation" error
Instrumentation and Controllers	5% of estimated cost in addition to "formulation" error
Electrical Support Equipment	5% of estimated cost in addition to "formulation" error
Vapor Generator	5% of estimated cost in addition to "formulation" error
Desuperheat/Condenser (Binary)	5% of estimated cost in addition to "formulation" error
Pump	
Reinjection	8% of estimated cost
Other	5% of estimated cost
Indirect Field Expense	5% of estimated cost in addition to "formulation" error
Engineering and Design	5% of estimated cost in addition to "formulation" error
Contractor's Fee	5% of estimated cost in addition to "formulation" error
Contingency	5% of estimated cost in addition to "formulation" error

(a) "Routine" error standard deviations are measures of the variances between GEOCOST estimates and actual costs for a facility of the reference plant design resulting from expected minor variations in site conditions that are not estimatable.

The combined variance resulting from both these error sources is "model" error. Table 13 lists typical steam cycle power plant costs and standard deviations of estimated costs resulting from this "model" error. Table 14 lists typical costs and standard deviations for binary cycle plants. Total plant cost standard deviations are listed in Tables 15 and 16 for an even wider range of steam and binary plants. No variance estimates are available for transmission system costs.

**TABLE 13. Cost Estimates and "Model" Error Standard Deviations
for Typical Steam Power Plants(a)**

Account	Account Description	10 MW Gross/450°F		55 MW Gross/450°F		100 MW Gross/450°F	
		Cost (\$K)	% Std. Deviation	Cost (\$K)	% Std. Deviation	Cost (\$K)	% Std. Deviation
1.1	Piping and Insulation	343	9.9	814	10.0	1241	10.0
1.2	Crane	213	5.2	244	4.9	275	5.1
1.3	Turbogenerator	1,571	15.5	6,590	6.4	10,898	6.2
1.6	Flashers (Plant-Located Units)	147	12.2	394	12.4	557	12.4
1.9	Misc. Process Support Equipment	40	85.0	172	32.0	286	16.1
1.10	Instrumentation and Controllers	184	16.4	467	9.3	735	9.4
1.12	Electrical Support Equipment	89	12.9	273	9.8	445	9.0
1.16	Condenser	640	17.7	1,402	6.6	2,162	6.8
1.18	Buildings, Foundations, and Support Equipment	614	4.1	1,958	7.0	3,303	7.6
1.19	Gas Ejectors (Steam Driven)	141	15.6	219	9.1	271	8.9
1.20	Cooling Water Pump	74	5.4	185	4.9	275	5.1
1.21	Flash Water Reinjection Pump (Plant-Located Flasher Unit)	35	8.6	102	7.8	148	8.1
1.22	Cooling Tower Reinjection Pump	5	0.0	14	7.1	20	10.0
1.23	Condensate Pump	86	4.7	130	5.4	184	4.9
2.1	Cooling Tower System (Forced Draft Wet)	219	9.6	1,195	9.8	2,168	9.8
3.0	Switchyard System	405	4.0	972	4.0	1,323	4.0
5.1	Indirect Field Cost	481	10.8	1,513	8.2	2,429	8.3
5.2	Engineering and Design	634	10.4	1,997	8.0	3,206	8.1
5.3	Contractors Fee	<u>264</u>	<u>10.3</u>	<u>832</u>	<u>8.0</u>	<u>1,336</u>	<u>8.1</u>
	Total Power Plant Cost	6,185	4.7	19,473	2.7	31,262	2.8

(a) "Model" error standard deviations are measures of the variances between GEOCOST estimates and actual costs for a facility of the reference plant design.

TABLE 14. Cost Estimates and "Model" Error Standard Deviations
for Typical Binary Power Plants(a)

Account	Account Description	10 MW Gross/350°F		55 MW Gross/350°F		100 MW Gross/350°F	
		Cost (\$K)	% Std. Deviation	Cost (\$K)	% Std. Deviation	Cost (\$K)	% Std. Deviation
1.1	Piping, Insulation and Tanks	931	10.0	5,108	10.0	9,284	10.0
1.2	Crane	213	5.2	244	4.9	275	5.1
1.3	Turbogenerator	1,085	12.1	2,970	12.1	4,854	12.0
1.5	Vapor Generator(s)	573	8.0	2,165	8.1	3,449	8.1
1.9	Misc. Process Support Equipment	40	85.0	172	32.0	286	16.1
1.10	Instrumentation and Controllers	239	10.0	915	9.5	1,481	9.3
1.12	Electrical Support Equipment	113	11.2	465	8.9	783	8.6
1.16	Condenser	372	8.1	1,402	8.1	2,234	8.1
1.18	Buildings, Foundations, and Support Equipment	449	16.3	1,433	16.3	2,156	16.3
1.20	Cooling Water Pump	112	5.4	329	4.9	505	5.0
1.21	Reinjection Pump (Plant-Located)	53	7.5	153	7.8	222	8.1
1.23	Condensate Pump	97	5.2	212	5.2	350	5.1
1.23	Working Fluid Feed Pump	309	4.9	1,572	5.0	2,780	5.0
1.24	Working Fluid Booster Pump	67	4.5	452	5.1	885	5.0
2.1	Cooling Tower System (Forced Draft Wet)	382	9.7	2,094	9.8	3,806	9.8
3.0	Switchyard System	405	4.0	972	4.0	1,323	4.0
5.1	Indirect Field Cost	544	8.7	2,066	8.6	3,467	8.7
5.2	Engineering and Design	718	8.3	2,727	8.4	4,577	8.4
5.3	Contractors Fee	299	8.3	1,136	8.3	1,907	8.4
	Total Power Plant Cost	7,001	3.0	26,587	3.0	44,624	3.1

(a) "Model" error standard deviations are measures of the variances between GEOCOST estimates and actual costs for a facility of the reference plant design.

TABLE 15. "Model" Error Total Cost Percent Standard Deviation for Typical Steam Power Plants(a)

Gross Plant Power	Reservoir Temperatures, %			
	400°F	450°F	500°F	550°F
10 MW	4.5	4.7	4.9	5.1
30 MW	3.0	3.1	3.2	3.3
55 MW	2.7	2.7	2.8	2.8
100 MW	2.9	2.8	2.7	2.7

(a) "Model" error standard deviations are measures of the variances between GEOCOST estimates and actual costs for a facility of the reference plant design.

TABLE 16. "Model" Error Total Cost Percent Standard Deviation for Typical Binary Power Plants(a)

Gross Plant Power	Reservoir Temperatures, %			
	300°F	350°F	400°F	450°F
10 MW	3.2	3.0	3.0	3.0
30 MW	3.4	3.0	2.7	2.7
55 MW	3.5	3.0	2.7	2.7
100 MW	3.7	3.1	2.7	2.7

(a) "Model" error standard deviations are measures of the variances between GEOCOST estimates and actual costs for a facility of the reference plant design.

Most often, the "formulation" error is much greater than the "routine" error. In these instances, the "formulation" error statistically dominates the smaller "routine" error to an extent that it is considered the lone source of error. However, in situations of only minor "formulation" error, the "routine" error will dominate. In these instances, the total or "model" error term is based on subjective estimates of this "routine" error.

GEOCOST estimates may differ to a greater extent from actual costs when simulating the costs of a facility not of the reference design. Two additional sources of estimating error will add to cost variances when estimating costs for facilities of these designs. The first is "design" error. "Design" errors result from the differences between the GEOCOST--reference design and the actual facility design. There are numerous facility designs that can be labeled as earlier generation designs and it is the differences between these designs and the GEOCOST reference design that result in cost differences.

The second error source is "site" error. "Site" errors are differences in working conditions that result from the facility being constructed at a location other than Albuquerque. Climate, the quality of labor available to the site, and construction worker commuting distances are examples of working conditions that vary between sites and consequently cause costs to vary.

In most instances, these two error sources will entirely negate any "model" error. While "model" error sources are independent and tend to cancel out each other, these two error sources are frequently related. When they are related, the errors may not be canceling, and variances may be excessive. For example, the installation of a transmission pipeline over very rough terrain is far more expensive than the installation of a pipeline over flat terrain. The pipeline design would be very complex requiring sophisticated supports and route configurations. These complexities would place material costs in the upper ranges of the "design" variance. Labor would also be very expensive because of the remote worksite and long commuting distances. This would place labor costs in the upper ranges of the "site" variance. Under these conditions, the variances would not cancel resulting in a large combined variance.

The extent of these variances can only be estimated subjectively. Actual power plant total costs may vary from GEOCOST estimates with a standard deviation of 15 to 20% due to "design" source differences alone. For transmission systems, the total cost standard deviations could be as high as 50 or 75%. "Site" source differences may result in total cost standard deviations of up to 10%. These two error sources reflect most of the real differences found between GEOCOST estimates and actual costs.

COMPARISONS

GEOCOST estimates were compared with other geothermal facility capital cost estimates to establish the validity of GEOCOST as an estimating tool. Planning study cost estimates for the following seven facilities were available for comparison.

- Bechtel Corp., 59.1 MW flashed steam power plant, January 1976,
- EPRI, 55.0 MW flashed steam power plant, January 1976,
- Aerojet Nuclear, 15 MW flashed steam power plant, October 1974,
- EPRI, 64.3 MW binary power plant, January 1976,
- TRW, 10 MW binary power plant, January 1975,
- AEC/LBL, 10 MW binary power plant, October 1974,
- BNW, hypothetical transmission pipeline, January 1975.

These estimates can be expected to differ. Differences in facility designs, labor costs and working conditions, the categorization of facility components into cost accounts, and cost estimating techniques contribute to these differences. GEOCOST estimates capital costs for facilities of GEOCOST-determined design and not for facilities of planning study design.

All costs are in January 1977 dollars. The Bechtel and EPRI study cost estimates were escalated by 7% to achieve GEOCOST-equivalent price levels. In the TRW and BNW estimates, costs were escalated by 18%. The remaining studies, Aerojet Nuclear and AEC/LBL required an escalation rate of 23%.⁽³⁵⁻³⁸⁾

STEAM PLANT

The Bechtel study estimates costs for a two-flash stage, 59.1 MW gross, flashed steam cycle power plant at Heber, California.⁽²⁰⁾ Estimates include costs for stainless steel reinjection pumps. No contingency allowance is included in the GEOCOST estimate to duplicate the estimating approach utilized by Bechtel. This comparison is shown in Table 17.

The difference in total cost between the two estimates is 16.4%. As can be expected, the Bechtel estimate is somewhat greater because the Bechtel facility is not of earlier generation design.

TABLE 17. Comparison of Bechtel and GEOCOST
Power Plant Capital Cost Estimates

SITE: Heber
PLANT SIZE: 59.1 MW Gross
TEMPERATURE: 360°F
CYCLE: Flashed Steam

<u>Account</u>	<u>Account Description</u>	<u>GEOCOST (\$K)</u>	<u>Bechtel (\$K)</u>
1.1	Piping, Insulation, and Tanks	2,068	3,739
1.2	Crane	247	Incl. in Account 1.18
1.3	Turbogenerator	9,040	11,139
1.6	Flashers (Plant-Located Units)	372	308
1.9	Misc. Process Support Equipment	183	432
1.10	Instrumentation and Controllers	684	1,043
1.12	Electrical Support Equipment	464	1,244
1.16	Condenser	1,758	926
1.18	Buildings, Foundations, and Support Equipment	2,081	3,238
1.19	Gas Ejectors (Steam-Driven)	191	Incl. in Account 1.9
1.20	Cooling Water Pump	411	401
1.21	Flash Water Reinjection Pump (Stainless Steel)	1,939	1,867
1.22	Cooling Tower Reinjection Pump	51	Incl. in Account 1.21
1.23	Condensate Pump	540	258
2.1	Cooling Tower System (Forced Draft Wet)	1,783	1,804
3.0	Switchyard System	1,009	1,272
5.1	Indirect Field Cost	2,288	2,931
5.2	Engineering and Design	3,007	3,638
5.3	Contractors Fee	<u>1,253</u>	<u>Incl. in Account 5.1</u>
	Total Power Plant Cost	29,419	34,240

The first EPRI estimate is for the conceptual design of a two-flash stage, 55.0 MW gross, flashed steam cycle power plant to be located at Heber, California. The planning study was prepared by Holt/Procon.⁽¹⁹⁾ The EPRI estimate does not include reinjection pump costs; however, both estimates do include an allowance for contingency. Table 18 contains this comparison.

TABLE 18. Comparison of EPRI and GEOCOST Capital Estimates

SITE: Heber

PLANT SIZE: 55.0 MW Gross

TEMPERATURE: 360°F

CYCLE: Flashed Steam

Account	Account Description	GEOCOST (\$K)	EPRI
1.1	Piping, Insulation, and Tanks	1,953	1,503
1.2	Crane	244	Incl. in Account 1.18
1.3	Turbogenerator	8,510	8,334
1.6	Flashers (Plant-Located Units)	357	334
1.9	Misc. Process Support Equipment	172	Incl. in Account 1.19
1.10	Instrumentation and Controllers	579	479
1.12	Electrical Support Equipment	350	Incl. in Account 3.0
1.16	Condenser	1,669	1,511
1.18	Buildings, Foundations, and Support Equipment	1,958	1,417
1.19	Gas Ejectors (Steam-Driven)	187	479
1.20	Cooling Water Pump	484	532
1.21	Flash Water Reinjection Pump	479	None
1.22	Cooling Tower Reinjection Pump	49	None
1.23	Condensate Pump	676	Incl. in Account 1.20
2.1	Cooling Tower System (Forced Draft Wet)	1,171	1,712
3.0	Switchyard System	972	1,532
5.1	Indirect Field Cost	1,981	2,526
5.2	Engineering and Design	2,615	3,179
5.3	Contractors Fee	1,090	2,568
5.4	Contingency Cost	<u>2,575</u>	<u>2,568</u>
	Total Power Plant Cost	28,071	28,674
	(Without Reinjection Pump)	27,273	

Total cost difference for this comparison is only slightly greater than 5%. Like the Bechtel estimate, the EPRI estimate is not for a facility of earlier generation design and estimated costs should be expected to be greater.

The Aerojet Nuclear proposal prepared by Rodgers Engineering is for a two-flash stage, 15 MW gross, flashed steam cycle power plant located at

Idaho Falls, Idaho.⁽²⁶⁾ The Aerojet estimate does not include costs for reinjection pumps, nor does either estimate include costs for a contingency allowance. This comparison is shown in Table 19.

TABLE 19. Comparison of Aerojet Nuclear and GEOCOST Capital Cost Estimates

SITE:	Idaho Falls		
PLANT SIZE:	15 MW Gross		
TEMPERATURE:	300°F		
CYCLE:	Flashed Steam		
Account	Account Description	GEOCOST (\$K)	Aerojet Nuclear
1.1	Piping, Insulation, and Tanks	1,247	167
1.2	Crane	216	Incl. in Account 1.18
1.3	Turbogenerator	3,786	2,514
1.6	Flashers (Plant-Located Units)	167	260
1.9	Misc. Process Support Equipment	57	Incl. in all Accounts
1.10	Instrumentation and Controllers	256	219
1.12	Electrical Support Equipment	132	1,451
1.16	Condenser	904	780
1.18	Buildings, Foundations, and Support Equipment	763	1,729
1.19	Gas Ejectors (Steam-Driven)	199	586
1.20	Cooling Water Pump	143	126
1.21	Flash Water Reinjection Pump	82	None
1.22	Cooling Tower Reinjection Pump	6	None
1.23	Condensate Pump	110	Incl. in Account 1.20
2.1	Cooling Tower System (Forced Draft Wet)	542	610
3.0	Switchyard System	498	Incl. in Account 1.12
5.1	Indirect Field Cost	911	1,247
5.2	Engineering and Design	1,202	582
5.3	Contractors Fee	501	Incl. in Account 5.1
	Total Power Plant Cost	11,722	10,271
	(Without Reinjection Pump)	11,600	

The Aerojet Nuclear conceptual design is more similar to earlier generation facility designs than other comparison designs. Total cost difference is less than 12%.

BINARY PLANT

The second EPRI estimate was also prepared by Holt/Procon.⁽¹⁹⁾ This estimate is for a 64.3 MW gross, binary cycle power plant using an isobutane working fluid to be located at Heber, California. The EPRI estimate does not include reinjection pump costs; however, both estimates include an allowance for contingency. Table 20 contains this comparison.

TABLE 20. Comparison of EPRI and GEOCOST Capital Cost Estimates

SITE: Heber

PLANT SIZE: 64.3 MW Gross

TEMPERATURE: 360°F

CYCLE: Binary

<u>Account</u>	<u>Account Description</u>	<u>GEOCOST (\$K)</u>	<u>EPRI</u>
1.1	Piping, Insulation, and Tanks	2,642	3,268
1.2	Crane	250	Incl. in Account 1.18
1.3	Turbogenerator	4,478	4,293
1.5	Vapor Generator	2,517	3,383
1.9	Misc. Process Support Equipment	196	180
1.10	Instrumentation and Controllers	1,408	516
1.12	Electrical Support Equipment	680	Incl. in Account 3.0
1.16	Condenser	2,891	Incl. in Account 1.5
1.18	Buildings, Foundations, and Support Equipment	1,595	1,602
1.20	Cooling Water Pump	445	Incl. in Account 1.24
1.21	Reinjection Pump (Plant-Located)	523	None
1.23	Condensate Pump	585	Incl. in Account 1.24
1.24	Working Fluid Feed Pump	3,271	1,35
1.25	Working Fluid Booster Pump	796	Incl. in Account 1.24
2.1	Cooling Tower System (Forced Draft Wet)	1,506	1,926
3.0	Switchyard System	1,053	2,085
5.1	Indirect Field Cost	2,484	3,022
5.2	Engineering and Design	3,278	3,337
5.3	Contractors Fee	1,366	2,782
5.4	Contingency Cost	<u>3,352</u>	<u>2,782</u>
	Total Power Plant Cost	35,515	30,496
	(Without Reinjection Pump)	34,724	

Total cost difference for this comparison is slightly greater than 12%. This is the only binary cycle power plant comparison where the GEOCOST estimate is greater than the planning study estimate.

The TRW study was prepared for the National Science Foundation.⁽²⁷⁾ Included in this study is a conceptual design and cost estimate for a 10 MW gross, binary cycle power plant using an isobutane working fluid. The design utilizes turbine-driven working fluid pumps and does not calculate costs for reinjection pumps. Unlike GEOCOST, the cycle does not contain a cooling water circuit but utilizes a dry-working fluid condenser. No contingency allowance is included in GEOCOST to duplicate TRW's estimating approach. This comparison is shown in Table 21.

Total cost difference between estimates is 7.6%. This difference is remarkably small considering the large differences in cooling water circuit design between GEOCOST and the TRW design.

The U.S. Atomic Energy Commission/Lawrence Berkeley Laboratory (AEC/LBL) study was prepared by Rodgers/Benham-blair.⁽²⁵⁾ The study designs and calculates costs for 10 MW gross, binary power plant to be located at Winnemucca, Nevada. The design utilizes turbine-driven working fluid pumps and an isobutane working fluid. Costs for reinjection pumps are not included in the planning study estimate. No allowance for contingency is contained in either estimate. Table 22 contains this comparison.

The AEC/LBL cooling water circuit design is also quite different from the GEOCOST reference design circuit. However, total cost difference is less than 6%.

TABLE 21. Comparison of TRW and GEOCOST
Capital Cost Estimates

SITE: Nonspecified
PLANT SIZE: 10.0 MW Gross
TEMPERATURE: 350°F
CYCLE: Binary

<u>Account</u>	<u>Account Description</u>	<u>GEOCOST (\$K)</u>	<u>TRW</u>
1.1	Piping, Insulation, and Tanks	430	754
1.2	Crane	213	Incl. in Account 1.18
1.3	Turbogenerator	1,217	1,389
1.5	Vapor Generator	540	1,794
1.9	Misc. Process Support Equipment	40	434
1.10	Instrumentation and Controllers	342	241
1.12	Electrical Support Equipment	162	509
1.16	Condenser	447	78
1.18	Buildings, Foundations, and Support Equipment	449	426
1.20	Cooling Water Pump	189	Incl. in Account 1.24
1.21	Reinjection Pump (Plant- Located)	123	None
1.23	Condensate Pump	196	Incl. in Account 1.24
1.24	Working Fluid Feed Pump	1,330	518
1.25	Working Fluid Booster Pump	227	Incl. in Account 1.24
2.1	Cooling Tower System (Dry Cooling)	1,796	2,464
3.0	Switchyard System	405	522
5.1	Indirect Field Cost	811	548
5.2	Engineering and Design	1,070	1,369
5.3	Contractors Fee	<u>446</u>	<u>Incl. in Account 5.1</u>
	Total Power Plant Cost	10,433	11,046

TABLE 22. Comparison of AEC/LBL and GEOCOST
Capital Cost Estimates

SITE: Winnemucca
PLANT SIZE: 10.0 MW Gross
TEMPERATURE: 392°F
CYCLE: Binary

Account	Account Description	GEOCOST (\$K)	AEC/LBL
1.1	Piping, Insulation, and Tanks	549	589
1.2	Crane	213	Incl. in Account 1.9
1.3	Turbogenerator	1087	1275
1.5	Vapor Generator	536	2113
1.9	Misc. Process Support Equipment	40	418
1.10	Instrumentation and Controllers	307	305
1.12	Electrical Support Equipment	154	437
1.16	Condenser	358	82
1.18	Buildings, Foundations, and Support Equipment	449	279
1.20	Cooling Water Pump	188	Incl. in Account 1.24
1.21	Reinjection Pump (Plant- Located)	134	None
1.23	Condensate Pump	195	Incl. in Account 1.24
1.24	Working Fluid Feed Pump	1014	416
1.25	Working Fluid Booster Pump	199	Incl. in Account 1.24
2.1	Cooling Tower System (Dry Cooling)	1770	2329
3.0	Switchyard System	405	448
5.1	Indirect Field Cost	760	527
5.2	Engineering and Design	1003	1076
5.3	Contractors Fee	418	Incl. in Account 5.1
	Total Power Plant Cost	9779	10294
	(Without Reinjection Pump)	9600	

TRANSMISSION SYSTEM

In the BNW comparison, cost estimates from the current transmission pipeline cost models were compared with estimates from cost models previously used in GEOCOST. This comparison is shown in Table 23. The current models were formulated from an entirely different cost basis and bare no resemblance to the previous models.

TABLE 23. Comparison of Previous and Current
GEOCOST Transmission System Capital
Cost Estimates

FACILITY: Transmission Pipeline

SITE: Hypothetical

(NOTE: Costs in thousands of dollars)

Account Description	300,000 lb/hr/well 302°F Temperature		700,000 lb/hr/well 302°F Temperature		300,000 lb/hr/well 482°F Temperature		700,000 lb/hr/well 482°F Temperature	
	Previous	Current	Previous	Current	Previous	Current	Previous	Current
Pipe	6586	2202	3934	1414	2394	972	1505	606
Insulation	1673	2615	828	1384	716	1219	402	658
Casing	--	2297	--	957	--	432	--	211
Site Work	--	2370	--	1232	--	744	--	386
Transmission Booster Pumps	212	474	123	221	83	170	51	83
Engineering and Design	<u>1016</u>	--	<u>506</u>	--	<u>384</u>	--	<u>235</u>	--
Total	9487	9958	5471	5208	3577	3537	2193	1944

Comparisons are based on the transmission system costs for four different geothermal reservoirs. Engineering and design costs for current cost model estimates are included in component accounts. Average total cost difference for the four systems is 5.9%.

CONCLUSIONS

GEOCOST estimates appear to closely approximate the planning study estimates. Even though some planning study designs cannot be considered earlier generation designs, estimate differences were never greater than 17%. In most instances, differences in facility design and account categorizations were responsible for cost account differences. Total cost differences were the result of variations in facility design and site conditions.

These differences are shown in Table 24 as a percent of the GEOCOST estimated cost. Total costs were adjusted in the GEOCOST estimates to correctly reflect the absence of plant located reinjection pumps found in many planning study estimates. Where GEOCOST estimates are greater than planning study estimates, the percent difference is negative; and where GEOCOST estimates are less than planning study estimates, the percent is positive. It appears that GEOCOST is not only an accurate predictor of installed costs but also a valid designer of geothermal facilities.

TABLE 24. Total Cost Comparison Percent Differences

<u>Comparison</u>	<u>Percent Difference</u>
Bechtel - 59.1 MW Flashed Steam	+16.4
EPRI - 55.0 MW Flashed Steam	+5.1
Aerojet Nuclear - 15 MW Flashed Steam	-11.5
EPRI - 64.3 MW Binary	-12.2
TRW - 10 MW Binary	+7.6
AEC/LBL - 10 MW Binary	+5.3
BNW - Transmission Pipeline (Average)	<u>+5.9</u>

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